RESPONSE TO LOCATIONAL PRICING ASSESSMENT – CALL FOR INPUT

This response presents the views of SSE's Energy Businesses which encompass all of SSE's generation and supply activities. A separate response will be submitted representing the views of SSEN Transmission.

SSE Renewables is a leading developer and operator of renewable energy across the UK and Ireland, with a portfolio of around 4GW of onshore wind, offshore wind and hydro. Our strategy is to drive the transition to a zero-carbon future through the world class development, construction and operation of renewable energy assets. We are aiming to deliver enough new renewable projects to generate 50TWh by 2031, a fivefold increase in renewables output, including Dogger Bank Wind Farm, currently the world's biggest offshore wind farm development, at 3.6GW.

SSE Thermal is a leading developer and operator of assets which play a key transitional role in the SSE Group and across the wider energy system. While providing much-needed system flexibility to ensure security and stability of supply in the short term, the business is also actively pursuing options to decarbonise its generation fleet progressively over the long term. SSE Thermal owns and operates 4GW of conventional thermal generation, including Keadby 2 which will become one of the world's most efficient CCGT power stations on completion of the current commissioning programme. SSE Thermal is also developing flexible low-carbon power including carbon capture projects in partnership with Equinor at Keadby and Peterhead as well as two hydrogen projects in the Humber.

SSE Distributed Energy focuses on investing in, building and connecting localised flexible energy infrastructure. This business area also develops solar and battery projects, operates heat networks, and offers integration, aggregation and trading capability.

SSE Business Energy provides energy and related services to businesses and public sector organisations across Great Britain.

ENGAGEMENT PROCESS AND THE CASE FOR REFORM

This Call for Input follows the first of three workshops which Ofgem plans to hold over the summer by way of stakeholder consultation on the possible introduction of a zonal or nodal wholesale market design. SSE is extremely concerned that Ofgem is progressing in this manner without also conducting a more thorough consultation process to firstly define the problem to which a solution is sought and secondly to assess the most efficient and best targeted intervention(s) to address that problem.

The current process may be intended to identify whether Locational Marginal Pricing (LMP) can, compared to the status quo, better enable a fully flexible, low carbon, low cost system necessary to meet net zero and energy security ambitions - but this is insufficient; it will also be necessary for Ofgem to establish whether LMP is likely to be a more effective intervention than other options that may deliver the same or better outcomes at better value and with lower risk.

The workshop material set out Ofgem's six-stage workplan in which the first stage, labelled "Case for change", was conspicuous in that no work appears to have been done in setting this out. Whilst there may be broad agreement amongst stakeholders that change is necessary to deliver net zero, it is important that Ofgem follows a robust process to assess the specific problems that any change is aimed at addressing. The process to explore the case for change would necessarily involve appropriate review of existing arrangements, identification of areas where these are not fit for purpose and a clearer focus on the range of options that might reasonably be considered to address the shortcomings so identified. By omitting this critical stage of the process, Ofgem risks proposing reforms that are suboptimal at best and which put at risk our ability to decarbonise the energy sector in a timely manner at best value for consumers.

This omission implies that Ofgem is uncritically accepting the arguments put forward by NG ESO in its proposal for reform, including its assertion that the system operator role is no longer the residual balancer due to inefficient siting of generation and demand. This is a questionable assessment for a number of reasons: market participants are effectively incentivised to balance their position; net imbalance volumes have not increased to a problematic level; the rises in BSUoS in recent years are driven by network congestion costs and not imbalance; most demand is unable to respond to locational signals; and generators are less able to respond to locational signals than NG ESO asserts due to the variety of other development constraints that effectively drive the choice of site for new generation. NG ESO did not provide evidence regarding why its role of dispatching some generators to mitigate congestion is problematic or carried out inefficiently. Nor did it explain why it could be better in principle to extend its role to centrally dispatch the whole market under LMP.

A more balanced assessment of the causes of high constraint costs might conclude that Connect and Manage has performed as intended to connect more low carbon generation faster in advance of associated network reinforcement. However, investment in the network infrastructure needed to deliver net zero is increasingly failing to keep pace with the rate of deployment of renewables. The Network Options Assessment (NOA) process, now augmented by the work to develop a Holistic Network Design (HND), can appropriately identify and prioritise network reinforcement – but the regulatory framework has put additional and undue hurdles in the transmission network owners' way, obstructing a more rapid and efficient network build. This has resulted in the Needs Case for critical reinforcement work to only be established *after* the point at which investment is needed. The slow regulatory process has therefore compounded the issue of network constraints by failing to keep pace with the growth of renewables, let alone make inroads to reduce the cost of constraints over time (highlighted by BSUoS forecasts not showing a reduction in constraint costs until the second half of this decade). This issue has been identified and commented on by many, with increased discussion of the need for anticipatory investment (AI) in both the development of offshore networks and for onshore reinforcement.

It is important to note that the evolving generation mix has been a response to Government energy policy and the ever more ambitious targets to deliver increased zero carbon generation and enhanced energy security earlier. The sites so far developed for offshore wind have been dictated by the leasing rounds conducted by the Crown Estate and the Crown Estate Scotland and developers therefore have a choice only on whether or not to invest. Developers do not have a choice on the location of these development opportunities. Other factors also drive (and restrict) the choice of suitable locations for the development of other technologies, including onshore wind, low carbon flexible generation (such as CCGTs with carbon capture and hydrogen) or, following the publication of the BESS, new nuclear units.

Recognising the policy drivers for the developing generation mix and the real-world constraints impacting location decisions for generation (and demand) underlines how important it is that Ofgem considers the wider context and alternative means to address perceived shortcomings of the current market arrangements.

SSE would ask Ofgem to undertake a wider review of available options for incremental regulatory improvements as a matter of urgency, and this should also be a focus for BEIS in the upcoming Review of Electricity Market Arrangements (REMA) consultation. Attention should also be focused on the more valuable solution which is to increase the transmission system capacity at speed to minimise the loss of low carbon, low cost, secure energy for GB consumers.

Taking these actions would reduce the risk of embarking on a long process to implement market reform that may be more technical, complex and disruptive than is necessary. It could avoid unhelpfully increasing the level of risk to be borne by generators, which would otherwise increase the cost of capital and consequentially increase cost to customers. The complexity of transitioning to LMP also risks diverting limited industry resource and attention from addressing more practical challenges for delivering net zero. It is clear that the introduction of a more granular wholesale market is likely to reduce the rate of progress towards a net zero secure energy system and increases its cost, at least during the period of transition, and likely beyond. These points are explored more fully in the answers that follow.

ANSWERS TO CALL FOR INPUT QUESTIONS

This section presents the views of SSE's Energy Businesses on aspects covered by the questions raised. Also provided, as an Annex to this response, is a report that SSE has commissioned from LCP and Frontier Economics which provides additional insight and commentary on the modelling approach set out by FTI at the first workshop. The Annex is primarily focused on Question 3 and the points raised are summarised in a list of key recommendations. SSE supports these recommendations and, rather than repeating all of the same arguments here, focuses below on the factors that we see as most critical in the assessment of the possible impacts of LMP.

1. The key opportunities associated with introducing more granular locational pricing in GB

As noted above, there is a need for Ofgem to conduct a wider assessment of the drivers of high congestion costs and the alternative policy interventions that might better address these. In that respect, the key opportunity in assessing the introduction of more granular locational pricing in GB is that it provides a suitable stimulus to undertake that wider assessment.

2. The key implementation challenges, risks and mitigations.

Impact on cost of capital

The introduction of LMP would be the biggest change to the GB energy market since NETA in 2001 (extended to BETTA in 2005). This shift would increase the cost of capital for generators as the result of four main factors:

- greater uncertainty in forecast wholesale prices over the asset life at the point of investment;
- additional risks imposed on generators which they cannot manage;
- inability for generators to hedge exposure to lower wholesale prices; and
- impact of a reducing number of generators and investors.

The first of these is an intrinsic feature of markets with LMP – imperfect information means it is impossible to accurately forecast deeply granular locational prices with any confidence. This factor necessarily increases the uncertainty for investors, even compared to the current challenge of forecasting TNUoS. This increased uncertainty essentially makes investment in generation higher risk than the current arrangements, with consequentially higher cost of capital for generators. It is notable that given the scale of investment required to meet targets for offshore wind, even small changes in the cost of capital can result in large additional costs over time. The UKERC has estimated[1] that for every percentage point increase in the cost of capital, the £15bn annual financing cost of offshore wind increases by £1bn per year. The UKERC estimate is a useful reference but the expected impact on the cost of capital is an area that will receive further consideration as part of this process.

Secondly, LMP would also expose generators to risks which they are not able to manage or control. In particular, generators would be exposed to additional costs for all instances of delays to transmission build or unavailability of network capacity for any reason despite the fact that generators are not in a position to manage the risk of these events occurring. The transfer of this risk to generators would create moral hazard by softening the impetus on those who do have some measure of control, ESO and Ofgem, by creating the illusion that levels of generation constraint are the sole responsibility of the generators who have chosen to locate in constrained areas.

The third factor arises from the fact that there is no means for generators to adequately hedge their exposure to low wholesale prices in export constrained zones of the network. Financial Transmission Rights (FTRs) have been identified as a means to manage this risk but, despite their use in other markets, should not be regarded as a panacea. It is extremely complex to design effective markets that would provide sufficient liquidity in the products needed to meet the needs of intermittent generators and specifically products with appropriate term and shape. The limitations of suitable hedging options mean that generators in parts of the system will essentially lose the opportunity to earn infra-marginal rent (which Ofgem has previously identified[2] as a critical feature in the design of wholesale markets as it "*fulfils the function of sending investment signals and also provides a means of cost recovery for capital investment"*).

Finally, it is worth noting the potential impact that more complexity and a need for active risk management (i.e. employing a diverse portfolio) could lead to fewer operators in the market; investors favouring other markets, alongside a period of uncertainty; and which would have an upward pressure on the cost of capital by reducing the pool of available capital. This effect is illustrated by the share price impact on electricity generators operating in GB on the back of rumours of a prospective windfall tax or other near-term interventions referenced in media articles. We see a similar risk emerging with assumptions being made about the case for change without clearly defining the problem. It is vital that any prospect of fundamental reforms under the REMA process is subject to the appropriate level of consultation, evidence, challenge and scrutiny.

Wholesale liquidity

The introduction of LMP risks materially negatively impacting wholesale liquidity. Ofgem has previously identified the importance of liquidity in supporting competition in generation and supply, intervening in the market to introduce the Secure and Promote licence condition in 2014 to address its concern that wholesale

[1] See *Risk and investment in zero-carbon electricity markets* (https://ukerc.ac.uk/publications/zero-carbon-electricity/), the UK Energy Research Centre, Nov 2021.
[2] See Ofgem's submission to the CMA: *Market Investigation Reference: Assessing the Wholesale Market*, Dec 2014.

market liquidity was too low (despite trading at NBP on the basis of a single, national energy price) and that this presented a barrier to entry that is bad for consumers. The possible impact on liquidity of the introduction of LMP will need to be very carefully assessed as part of this process. Whilst trading at 'hubs' may provide liquidity, it is not clear that this would arise naturally in a market with LMP. It is also likely that liquidity will vary between different hubs, dependent on their size. For zones or nodes where the price does not closely follow a hub price there is scope for FTRs to support forward liquidity but, as discussed above, it is not clear that these will be able to provide liquidity in products that adequately match the exposures of generators.

Impact on delivery of net zero

LMP would tend to favour generation locating further south, closer to demand centres, partly due to the lower degree of commercial risk in the south rather than it being better value for the system. Unfortunately, in the south the availability of good renewables resource is more limited. LMP may therefore limit renewable deployment in Northern GB which, in turn, due to the likely lower generation rates and the limited scope for renewable development in Southern GB, would result in higher unabated gas generation, increased carbon emissions and prolonging GB's dependency on imported gas.

A shift to more Southern renewables may also cause a technology shift from wind to PV, requiring a higher total capacity of generation with energy concentrated in a shorter number of hours in the summer time compared with wind that generates more in the winter when it will be needed to decarbonise winter demand for heat and transport. A greater concentration of renewable generation in southern areas would also cause a loss of the externality system benefits of a more geographically diverse wind fleet that could deliver a more stable and reliable generation profile that would make the system easier to manage, more secure and reduce the cost of flexible firm low carbon generation capacity required. It is therefore essential that the assessment of LMP properly accounts for the value of technological and geographical diversity in the generation mix.

The delivery of net zero would also be impacted through interactions with the CfD regime, with implications for how this might evolve. At the point a generator makes its Final Investment Decision (several years in advance of first export) it must assess expected revenue for energy produced over the life of the asset. It is not necessarily the case that capital costs would be expected to be recovered within the 15-year term of the CfD and therefore the value of the merchant tail of operation beyond that term can be critical to the investment. The degree of uncertainty in forecast prices under LMP and the higher cost of capital noted above, can be expected to lead to an upward pressure on future CfD auctions compared to the outcome under current market arrangements. This impact would go against the original rationale for the introduction of CfDs, which was the recognition that to deliver decarbonisation at best value, it was better for customers to reduce investor cost of capital and hurdle rate as much as possible by avoiding exposing investors to unnecessary, or unhelpful risks. A number of issues therefore need to be considered in the assessment of LMP impacts, including the possible grandfathering of existing CfD contracts and the degree to which new CfDs will expose generators to nodal prices during the term of the contract.

Implementation timescale

Implementation of LMP is very likely to be significantly longer than NG ESO's optimistic estimate of 5 years. A protracted change process to introduce more granular pricing runs the significant risk that investment would reduce pending clarity on the regulatory framework or else increase the number of projects seeking higher returns (for higher risk) and/or grandfathering arrangements for CfDs to support the investment.

The modelled benefits of the introduction of LMP are likely to be greatly diluted if demand is not also exposed to the locational signal. However, it may not be politically acceptable for demand customers in the south to pay significantly higher prices than customers in the north, especially for the significant proportion of demand that cannot be expected to respond to locational signals. This consideration will need to be factored into the assessment of total system welfare impacts of the adoption of LMP.

A further issue that would tend to extend the implementation timescale is that current industry systems are unable to assign MPANs to more granular zones than DNO areas. So as well as the political considerations above, the technical feasibility of zonal/ nodal pricing also needs to be considered. Any move to more granular zones than the existing DNO licence areas would require a new system to identify and allocate MPANs by location. Any change in requirement would need either an entirely new approach or substantial change to be implemented to DNO systems for Meter Point Administration. This would be a significant and complex project that would require careful planning and coordination to implement.

3. The proposed approach to modelling zonal and nodal market designs.

The comments below are provided to complement the content provided in the Annex and emphasise the factors which SSE considers to be the most significant. Addressing these will increase the value of the modelling exercise and better inform further policy development.

Transparency

It is critical that Ofgem ensures that the modelling is completely transparent to stakeholders. Ideally, Ofgem will publish the model in its entirety (including the input data) as this is the most robust means of ensuring that stakeholders are able to properly understand the drivers of model output and therefore interpret the results. Whilst the modelling exercise cannot, in itself, point to the right answer for market design, it can help to illuminate the issues and key factors and sensitivities for further consideration. For this process to be effective, however, all parties should have equal access to the model assumptions so that alternative proposals can be assessed and understood on a fair basis.

Basis and scope of modelling exercise

The impact of LMP must be assessed based on total system welfare and not based on cost to customers. Redistribution may deliver a short-term customer saving but as a source of customer value it is unsustainable, poor regulatory practice and counterproductive as a long-term policy. This is because the consequence of redistribution, as noted above, would be to increase the cost of capital for generators which will lead to higher costs for customers in the longer term. Apparent savings arising from improvements in the efficiency of dispatch under LMP must be offset by the longer-term impact on system costs. If generators are unable to reliably earn infra-marginal rents, then the cost of the support required to ensure that there is adequate capacity with the right mix of generation and storage to deliver net zero will necessarily increase. Assessing impacts based on total system welfare is critical as this will flush out these long-term impacts of LMP.

SSE considers the scope of the modelling to be too narrow; it is critical that alternative policy options are also considered in the counterfactual. This should include the scope for reform of TNUoS to provide better targeted and better understood (and so more effective) signals at lower system cost and risk. Equally, earlier delivery of transmission reinforcement has the scope to improve system efficiency. For example, LMP will not alleviate the cost of congestion, it will instead redistribute the cost by moving it from customers (via BSUoS) onto generators instead, which will in turn be passed back to customers via less efficient routes such CfD, Capacity Mechanism, or energy market prices. By contrast, investment in increased transmission capacity (or suitably located storage that can time-shift generation to periods when the network is unconstrained) would genuinely alleviate constraints. Genuinely avoiding constraints could deliver better system welfare by avoiding the opportunity cost of lost zero short-run marginal cost low carbon energy and correspondingly avoid the need to burn gas and emit carbon to make up the shortfall.

The modelling should account for the impacts of these alternative policy options in the counterfactual and the assessment of costs and benefits must be based on total system welfare if Ofgem is to reach a sound recommendation on the way forward.

Modelling of transmission capacity

The assumed transmission build will be a critical driver of the modelling results**.** The factual and counterfactual modelling should factor in transmission investment that is responsive to the generation deployment, to take account of the cost of constrained generation and increase the network capacity as a result. The proposal that transmission capacity is modelled based on current planned investment, which does not flex in line with the modelled evolution of generation or demand, risks undermining the assessment process altogether. Similarly, ending the modelling period in 2041 due to a lack of public data on transmission development post this date will result in the analysis failing to consider the impact of LMP during a time period (the 2040s) where a significant portion of low-carbon capacity will be fully exposed to market prices.

Transmission capacity is one of the most important assumptions in the modelling assessment. As a result, more transparency is needed on the assumed build and availability of transmission, and scenarios around delivery of transmission capacity (timing and location, including faster build out) should be considered in order to reflect the materiality of transmission assumptions to the results of the assessment.. Relying on the model to endogenously build out transmission capacity in the modelling risks overstating the benefits attributable to LMP.

It would also be useful to test a sensitivity looking backwards and assessing the impact of a more proactive approach to transmission network build in the past would have had on today's market challenges, so as to inform future decisions on transmission build and market design.

Input data and scenarios

The proposed data sources for the modelling are not up to date and do take account of important developments since NOA6 and the ETYS were published. In particular, the BESS sets out significant elements of Government policy and the ongoing work on OTNR, the HND and the results of ScotWind are all significant. Equally as important, the FES 2021 does not reflect a wide enough range of scenarios –

alternative capacity mixes and higher demand (in line with scenarios used by BEIS and CCC) should also be tested as part of this assessment.

FTI has noted that commodity costs are the main determinant of short-run marginal costs of thermal power generators and therefore are a primary driver of wholesale power prices. For this reason, it is important to run modelling scenarios that explore the variability in these critical inputs. The FTI reference prices follow the IEA's World Economic Outlook beyond 2030 – this forecast is a relatively low-priced scenario so, at the very least, an additional scenario is needed to reflect the significant scope for much higher outturn prices during the modelled period. A further consideration is the impact that differentials in gas prices between GB (where there is significant LNG and pipeline capacity compared to demand) and interconnected EU states. Observations in the market this week demonstrate that gas prices should not be assumed to equalise, particularly as the EU works to reduce dependence on Russian gas. Lower gas prices in GB can and do arise, resulting in larger spark spreads as GB thermal generation is dispatched to meet electricity demand in interconnected markets. The difference in interconnector flows this leads to causes a swing of approx. 8GW in GB demand.

Relocation decisions

Model assumptions driving relocation decisions of generation, storage and demand must be made clear given the significant impact these will have on the modelling results. LMP will tend to favour generators located closer to demand centres, making it critical that realistic development constraints are recognised and accounted for in the model. Planning considerations, land availability and quality of renewable resource must all be factored in. LMP may lead to fewer onshore and offshore wind projects in the north, in favour of relatively more solar projects in the south for example, which would impact on the geographical diversity and technological mix of generation on the system. This can be expected to lead to higher correlation of output for each renewable technology (due to higher geographical concentration) with implications for security and independence of supply. These factors need to be offset against the wider aims of energy policy and the imperative to reduce our dependence on gas imports.